Air Quality Permitting
Statement of Basis

January 5, 2007

Permit to Construct No. P-060005

Mountain View Power, Inc., Gateway Power Plant
Boise, Idaho

Facility ID No. 001-00215

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AIR QUALITY DIVISION

PROPOSED FOR PUBLIC COMMENT

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Acronyms, Units, and Chemical Nomenclature

AACC	acceptable ambient concentrations
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	carbon monoxide
CT01	Siemens 501 F simple cycle, natural gas-fired combustion turbine
DEQ	Idaho Department of Environmental Quality
EI	emissions inventory
FH01	fuel dew point heater
dscf	dry standard cubic feet
EPA	U.S. Environmental Protection Agency
gr	grain (1 lb = 7,000 grains)
HAP	hazardous air pollutant
HHV	high heating value
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
MACT	Maximum Achievable Control Technology
MMBtu/hr	million British thermal units per hour
NAAQS	National ambient air quality standard
MW	megawatt
NESHAP	Nation Emission Standards for Hazardous Air Pollutants
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
PEH	Polyaromatic hydrocarbons
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	Prevention of Significant Deterioration
PTC	permit to construct
RATA	Relative Accuracy Test Audit
scfm	standard cubic feet per minute
SIP	State Implementation Plan
SO_2	sulfur dioxide
T/yr	tons per year
TAP	toxic air pollutant
$\mu g/m^3$	micrograms per cubic meter
UTM	Universal Transverse Mercator
VOC	volatile organic compound

1. PURPOSE

The purpose for this memorandum is to satisfy the requirements of IDAPA 58.01.01.200, Rules for the Control of Air Pollution in Idaho, for issuing permits to construct.

2. FACILITY DESCRIPTION

Mountain View Power, Inc. proposed to construct and operate the Gateway Power Plant in Boise. The power plant is a simple cycle, natural gas-fired combustion turbine rated at nominal 180 MW at 59^{o}F. The plant will be used to meet peak system load requirements.

3. FACILTY / AREA CLASSIFICATION

The facility is not a major facility as defined by IDAPA 58.01.01.205, because its potential to emit is limited below 250 T/yr, the applicable PSD trigger. The facility is not a designated facility as defined by IDAPA 58.01.01.006.26. The facility is a major facility as defined by IDAPA 58.01.01.008.10.c, because it emits or has the potential to emit a regulated pollutant in amounts greater than 100 T/yr. The Standard Industrial Classification code for the facility is 4911 (i.e., a simple-cycle gas turbine power generation facility).

The facility is located within AQCR 63 and UTM zone 11. The facility is located in Ada County which is classified attainment for PM_{10} and CO, and unclassifiable for all criteria air pollutants.

The AIRS information provided in Appendix A defines the classification for each regulated air pollutant at the facility.

4. APPLICATION SCOPE

Mountain View Power, Inc. proposed to construct and operate the Gateway Power Plant in Boise. The emissions sources associated with the facility are a Siemens Westinghouse Model 501F (S 501F) simple cycle natural gas-fired combustion turbine (CT01) and a fuel dew point heater (FH01).

4.1 Application Chronology

February 1, 2006	DEQ received the PTC application from Mountain View Power, Inc. for their Gateway power plant in Boise.
March 3, 2006	DEQ declared the application complete.
June 2, 2006	DEQ issued draft PTC to Mountain View Power, Inc.
September 15, 2006	DEQ issued a second draft PTC to Mountain View Power, Inc. for the facility, because the facility is subject to new NSPS promulgated on July 6, 2006.
November 28, 2006	DEQ issued the third draft PTC to Mountain View Power, Inc. for the facility to address the facility’s comments on the second draft PTC.

5. PERMIT ANALYSIS

This section describes the regulatory requirements for this PTC.

5.1 Equipment Listing

Simple Cycle Natural Gas-Fired Combustion Engine (CT01)

Manufacturer:	Siemens Westinghouse
Model:	Siemens 501 F Combustion Turbine (S 501F)
Rated heat input capacity:	1,054 - 2,024 MMBtu/hr based on HHV
Nominal rating:	180 MW at 59ºF (greater than 200MW at -20 ºF)
Fuel type:	Natural gas
Emissions control device:	Ultra Dry Low NO_x (DLN++) combustors

Stack Information

Stack height:	60 feet
Stack diameter:	28 feet
Stack flowrate:	492,586 – 827,279 scfm
Stack temperature:	1032 - 1127 °F

Fuel Dew Point Heater (FH01)

Manufacturer:	Sivalls IH-6624-T1-3.6MM-6S or equivalent
Rated heat input capacity:	3.6 MMBtu/hr
Fuel type:	Natural gas

Stack Information

Stack height:	18 feet
Stack diameter:	2.0 feet
Stack flowrate:	2,369 acfm
Stack temperature:	1,000 °F

5.2 Emissions Inventory

A detailed emissions inventory (EI), including toxic air pollutant (TAP) emissions, was provided in the PTC application. The EI has been reviewed by DEQ. It appears to be acceptable with facility's proposed monitoring method. Tables 5.1 and 5.2 provide a summary of the EI for criteria pollutants and TAPs.

Table 5.1 MAXIMUM EMISSIONS ESTIMATES[a]

Emissions Unit	PM_{10}		SO_2		VOC		NO_x		CO	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
CT01	30.96[b]	130.6[c]	111.4[d]	248.04[e]	159.0[f]	120[g]	92.1[f]	247.1[e]	1644.9[f]	247.4[e]
FH01[h]	0.03	0.13	0.22	0.96	0.02	0.09	0.38	1.91	0.32	1.60
Total		130.7		249 [a]		120		249 [a]		249 [a]

[a] The estimated annual emissions of SO_2, NO_X, and CO were greater than 250 tons/yr. Each of them was arbitrarily set to 249 tons/yr in the application in order for the facility to stay as PSD minor source. The CEMS for NO_X, and CO will be used to ensure compliance with the NO_X, and CO emissions limits. The recordkeeping with calculations and fuel sulfur content data will be used to ensure compliance with the emissions limit of SO_2.

[b] Maximum hourly emissions for PM_{10} were calculated by multiplying maximum dry standard exhaust flowrate with EF of 10.0 mg/m^3 instead of manufacturer's data. Per May 2, 2006, email from the consultant, it is the factor represents the maximum potential PM_{10} emission rate for natural gas fired combustion turbines. It is more conservative estimation.

[c] PM_{10} annual emissions were calculated by multiplying maximum annual average hourly rate of 29.82 lb/hr to 8,760 hr/yr and divided by 2000 lb/ton.

[d] Maximum hourly emissions for SO_2 were calculated using fuel sulfur content of 20 gr/100 dscf (or 680 ppmw) rather than manufacturer's data. Assuming all the sulfur in the fuel is converted to SO_2.

[e] T/yr of CT01 = 249 tons/yr – FH01 emissions in tons/yr.

[f] Maximum hourly emissions for VOC, NO_X, and CO were calculated based on startup and shutdown emissions rates which were the worst hourly emissions rates. VOC emissions were expressed as methane.

[g] VOC annual emissions was calculated by multiplying annual maximum hourly rate of 27.40 lb/hr to 8,760 hr/yr and divided by 2000 lb/ton.

[h] Emissions factor from AP-42 Section 1.4 (rev. 3/98). 10% safety factor (contingency increase) was used in the application.

Table 5.2 MAXIMUM TAP EMISSIONS ESTIMATES[a]

TAPs	CT01	FH01	Total
	lb/hr	lb/hr	Ton/yr
Acetaldehyde (HAP)	0.08100	ND	0.35478
Acrolein (HAP)	0.01300	ND	0.05694
Benzene (HAP)	0.02400	Negligible	0.10512
Ethylbenzene (HAP)	0.06500	ND	0.28470
Formaldehyde (HAP)	1.40000	Negligible	6.13200
Naphthalene (HAP)	0.00260	Negligible	0.01139
PAH	0.00450	Negligible	0.01971
Propylene Oxide (HAP), less than	0.05900	ND	0.25842
Toluene (HAP)	0.26000	Negligible	1.13880
Xylenes (HAP)	0.13000	Negligible	0.56940
Cadmium (HAP)	ND	3.88E-06	1.70E-05
total			8.93

[a] Hourly emissions were the worst hourly emissions among all the operation scenarios.

[b] ND = no data

5.3 Modeling

The facility has demonstrated compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The facility has also demonstrated compliance to DEQ's satisfaction that the ambient impact of emissions from this facility will not exceed any AAC or AACC for TAPs. A summary of the modeling analysis can be found in the modeling memo in Appendix B.

Table 5.3 FULL IMPACT ANALYSES

Pollutant	Averaging Period	Modeled Design Concentration ($\mu g/m^3$)[a]	Background Concentration ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	NAAQS[b] ($\mu g/m^3$)	Percent of NAAQS
PM_{10}[c]	24-hour	6.2[d] (9.2[e])	84	90.2 (93.2)	150	60 (62)
Sulfur Dioxide (SO_2)	3-hour	89.2[d] (126.6[f])	42	131 (169)	1,300	10 (13)
	24-hour	20.9[d] (46.7[f])	26	46.9 (72.7)	365	13 (20)
	Annual	3.1[g] (4.5[g])	8	11.1 (12.5)	80	14 (16)
Carbon Monoxide (CO)	1-hour	1224.9[d] (2806.1[f])	12,200	13,425 (15,006)	40,000	34 (38)
	8-hour	200.9[d] (1202.3[f])	6,800	7,001 (8,002)	10,000	70 (80)
Nitrogen Dioxide (NO_2)	Annual	6.2[g] (8.3[g])	40	46.2 (48.3)	100	46 (48)

a. Micrograms per cubic meter. Values in parentheses are those obtained from DEQ verification analyses
b. National Ambient Air Quality Standards
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
d. Maximum 1st highest modeled concentration using a five-year data set
e Maximum 6th highest modeled concentration using a five-year data set
f. Maximum 2nd highest modeled concentration using a five-year data set
g. Maximum annual impact from modeling five separate years

5.4 Regulatory Review

This section discusses and documents DEQ's regulatory analysis of the proposed project with respect to applicable provisions of the Rules for the Control of Air Pollution in Idaho:

IDAPA 58.01.01.201..............................Permit to Construct Required

This facility proposed to build a brand new power plant. The proposed project does not qualify for an exemption under Sections 220 through 223 of the Rules; therefore, a Permit to Construction is required.

IDAPA 58.01.01.203.02..........................NAAQS

"No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:….02. NAAQS…."

The modeling memo is under development at this time.

IDAPA 58.01.01.203.03..........................Toxic Air Pollutants

"No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:….03. Toxic Air Pollutants Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586."

The emissions of Acetaldehyde, Benzene, Cadmium, Formaldehyde, and Polyaromatic hydrocarbons (PAH) exceeded their respective screen emissions levels. These five TAPs were modeled, and the modeled ambient concentrations were less than their respective acceptable ambient concentrations (AACC). Therefore, the facility has demonstrated compliance with IDAPA 58.01.01.203.03.

IDAPA 58.01.01.625..............................Visible Emissions

This regulation states that any point of emission shall not have a discharge of any air pollutant for a period aggregating more than three minutes in any 60-minute period of greater than 20% opacity. The emissions points at this facility are subject to this regulation.

IDAPA 58.01.01 675..............................Fuel Burning Equipment

This regulation establishes particulate matter emission standards (grain loading standards) for fuel burning equipment. Fuel burning equipment is defined in IDAPA 58.01.01.006.41 as, "*Any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer*."

This regulation is applicable to FH01. The calculated PM concentration of the FH01 flue gas is 0.005 gr/dscf @3% O_2. FH01 are in compliance with the grain loading standard. Therefore, no specific monitoring requirement is included in the permit as long as FH01 is fired by natural gas.

40 CFR 60 Subpart KKKK ....Standards of Performance for Stationary Combustion Turbines

The combustion turbine is subject to 40 CFR 60 Subpart KKKK which was promulgated on July 6, 2006. As a result, it is exempt from 40 CFR 60 Subpart GG.

40 CFR 72 ....Acid Rain Program

The proposed facility will be subject to the Acid Rain Program requirements of Parts 72 through 78. The Acid Rain Permit application requirements of 72.9(a) and the monitoring requirements of 72.9(b) have been applied to the facility. It should be noted that the alternative monitoring requirements given by 40 CFR 75, Subpart E, may be used in lieu of 72.9(b). As part of 72.9(a), the facility must comply with the requirements of 40 CFR Part 72, Subpart C. To implement the monitoring requirements, the permittee must comply with 40 CFR Part 75.

40 CFR 61 ....National Emission Standards For Hazardous Air Pollutants

The facility is not subject to any NESHAP standards.

Non-applicable

40 CFR 63 Subpart YYYY ....National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

The combustion turbine is not located at major source of HAP emissions. It is not subject to this MACT.

5.5 Permit Conditions

5.5.1 Facility-Wide Conditions

This section of the permit contains conditions that are generally applicable to the facility. The conditions include fugitive dust requirements, odor requirements, visible emissions requirements, and monitoring and recordkeeping requirements for each (for enforceability). The conditions also include requirements to submit permit applications for the Tier I operating permit program and Acid Rain Program as applicable.

5.5.2 Combustion Turbine Conditions (CT01)

5.5.2.1 Permit Conditions 3.1 and 3.2 provide a brief description of the combustion turbine and its NO_X control device.

5.5.2.2 Permit Condition 3.3 is the NO_X emissions limit taken from 40 CFR 60 Subpart KKKK.

The corresponding operating, monitoring, recordkeeping, reporting, the performance test requirements taken from 40 CFR 60 Subpart KKKK are included in Permit Conditions 3.6, 3.9, 3.14, 3.16, 3.17, 3.18, 3.27, and 3.28 to ensure that the permittee meets the NO_X emissions limit.

5.5.2.3 Permit Condition 3.4 is the SO_2 emissions limit taken from 40 CFR 60 Subpart KKKK.

The corresponding operating, monitoring, recordkeeping, reporting, the performance test requirements taken from 40 CFR 60 Subpart KKKK are included in Permit Conditions 3.6, 3.10, 3.11, 3.14, 3.19, and 3.29 to ensure that the permittee meets the NO_X emissions limit.

5.5.2.4 Permit Condition 3.5 establishes annual emissions limits for NO_X, SO_2, and CO in order to keep the facility as PSD synthetic minor.

Permit Condition 3.12 requires the permittee to use CO-CEMS to continuously monitor the CO emissions from the combustion turbine.

Permit Condition 3.13 requires the permittee to develop a protocol to quantify annual NO_X, SO_2, and CO emissions, and to monitor and record NO_X, SO_2, and CO emissions rates. The monitoring data obtained in Permit Conditions 3.9 through 3.12 is required to be used in the quantification of annual emissions in Permit Condition 3.13. The permittee is not allowed to start up the combustion turbine until the protocol is approved by DEQ in accordance with Permit Condition 3.8.

Permit Condition 3.7 limits the turbine fuel type as natural gas exclusively.

5.5.2.5 Permit Condition 3.15 requires all the monitoring data obtained in Permit Condition 3.9 through 3.12 to be kept on site for a minimum of five years and shall be made available to DEQ representatives upon request.

5.5.2.6 Permit Conditions 3.20 and 3.21 requires the submission of performance test protocols and performance test reports in accordance with IDAPA 58.01.01.157.

5.5.2.7 Permit Condition 3.23 requires the submission of initial certification, recertification, and monitoring plans for NO_X-CEMS as required by 40 CFR 75 Subpart G.

5.5.2.8 Permit Conditions 3.22, and 3.24 through 3.26 requires the submission of the information (e.g. RATAs) of the CEMS.

5.5.3 Fuel dew point Heater (FH01)

5.5.3.1 Permit Condition 4.1 provides a brief description of fuel dew point heater. Permit Condition 4.2 indicates there is no control device installed.

5.5.3.2 Permit Condition 4.3 establishes annual emissions limits for NO_X, SO_2, and CO in order to keep the facility as PSD synthetic minor.

Permit Conditions 4.5, 4.6, and 4.7 are operating requirement ensuring that the emissions limits are met. Permit Conditions 4.8, 4.9, and 4.10 are monitoring and recordkeeping requirements to ensure that the permittee is in compliance with the operating requirements in Permit Conditions 4.5, 4.6, and 4.7, consequently, in compliance with the emissions limits.

5.5.3.3 Permit Condition 4.4 is a grain loading standard for the heater. As long as the permittee using natural gas exclusively in the heater as required in Permit Condition 4.5, the permittee will meet the standard.

6. FEE REVIEW

Mountain View Power Inc. paid the $1,000 application fee required by IDAPA 58.01.01.224 on February 2, 2005. Total emissions increase of Mountain View Power Inc., Gateway Power Plant is greater than 100 tons per year. In accordance with IDAPA 58.01.01.225, the PTC processing fee is $7,500. The processing fee was received on June 29, 2006.

Table 6.1 EMISSIONS INVENTORY

Emissions Inventory			
Pollutant	**Annual Emissions Increase (T/yr)**	**Annual Emissions Reduction (T/yr)**	**Annual Emissions Change (T/yr)**
NO_X	249	0	249
SO_2	249	0	249
CO	249	0	249
PM_{10}	98.4	0	98.4
VOC	120	0	120
TAPS/HAPS	9.0	0	9.0
Total:	974.4	0	974.4
Fee Due	**$ 7,500.00**		

Mountain View Power Inc., Gateway Power Plant is a Tier I major facility as defined by IDAPA 58.01.01.008.10. Registration fees are applicable in accordance with IDAPA 58.01.01.387.

7. PERMIT REVIEW

7.1 Regional Review of Draft Permit

DEQ's Boise Regional Office was provided the draft permit for review on May 31, 2006, and second draft permit on September 8, 2006. The comments were received on May 31, 2006, and September 12, 2006, respectively. The permit related comments were addressed in the permit.

7.2 Facility Review of Draft Permit

The facility was provided the draft permit for review on June 2, 2006. The second facility draft was provided to the facility for review on September 15, 2006. The facility's consultant provided comments on the second draft permit through the phone conversation on October 5, 2006. The facility requested to put detailed requirements of 40 CFR 60 Subpart KKKK under statement of basis and to only keep the citations of 40 CFR 60 Subpart KKKK in the permit. As a result, the detailed applicable requirements of 40 CFR 60 Subpart KKKK that identified based on the information in the application is now included in the Appendix C of the statement of basis.

7.3 Public Comment

A public comment period will be provided in accordance with IDAPA 58.01.01.209.01.c.

8. RECOMMENDATION

Based on review of application materials and all applicable state and federal rules and regulations, staff recommends that the proposed PTC No. P-060005 be issued to Mountain View Power, Inc. for its Gateway Power Plant.

BR/SYC/bf Permit No. P-060005

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APPENDIX A

Aerometric Information Retrieval System Information

P-060005

AIRS/AFS[a] FACILITY-WIDE CLASSIFICATION[b] DATA ENTRY FORM

Facility Name: Mountain View Power, Inc, Gateway Power Plant
Facility Location: Boise
AIRS Number: 001-00215

AIR PROGRAM POLLUTANT	SIP	PSD	NSPS (Part 60)	NESHAP (Part 61)	MACT (Part 63)	SM80	TITLE V	AREA CLASSIFICATION A-Attainment U-Unclassified N- Nonattainment
SO_2	A	SM	A				A	U
NO_x	A	SM	A				A	U
CO	A	SM					A	A
PM_{10}	A						A	A
PT (Particulate)	A							
VOC	A						A	U
THAP (Total HAPs)	B						B	U
			APPLICABLE SUBPART					
			KKKK					

[a] Aerometric Information Retrieval System (AIRS) Facility Subsystem (AFS)

[b] AIRS/AFS Classification Codes:

A = Actual or potential emissions of a pollutant are above the applicable major source threshold. For HAPs only, class “A” is applied to each pollutant which is at or above the 10 T/yr threshold, **or** each pollutant that is below the 10 T/yr threshold, but contributes to a plant total in excess of 25 T/yr of all HAPs.

SM = Potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable regulations or limitations.

B = Actual and potential emissions below all applicable major source thresholds.

C = Class is unknown.

ND = Major source thresholds are not defined (e.g., radionuclides).

APPENDIX B

Modeling Memo

P-060005

MEMORANDUM

DATE: January 2, 2006

TO: Shawnee Chen, Senior Air Quality Engineer, Air Program

FROM: Kevin Schilling, Stationary Source Modeling Coordinator, Air Program

PROJECT NUMBER: P- 060005

SUBJECT: Modeling Review for the Mountain View Power, Inc., Gateway Power Plant Permit to Construct Application for a Natural Gas Fired Power Plant in Boise, Idaho

1.0 SUMMARY

Mountain View Power, Inc. (MVP), submitted a Permit to Construct (PTC) application for the Gateway Power Plant proposed for location in Boise, Idaho. Air quality analyses involving atmospheric dispersion modeling of emissions associated operations of the plant were submitted to demonstrate that the modification would not cause or significantly contribute to a violation of any ambient air quality standard (IDAPA 58.01.01.203.02). Arcadis-Greystone (Greystone), MVP's consultant, conducted the ambient air quality analyses, and DEQ analysts conducted supplemental analyses providing additional assurance that operation of the plant would not unacceptably impact air quality.

A technical review of the submitted air quality analyses and independent impact analyses were conducted by DEQ. The submitted modeling analyses, combined with DEQ's analyses: 1) utilized appropriate methods and models; 2) were conducted using reasonably accurate or conservative model parameters and input data; 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that predicted pollutant concentrations from emissions associated with the proposed facility were below significant contribution levels (SCLs); or b) that predicted pollutant concentrations from emissions associated with the facility, when appropriately combined with background concentrations, were below applicable air quality standards at all receptor locations. Table 1 presents key assumptions and results that should be considered in the development of the permit.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES

Criteria/Assumption/Result	Explanation/Consideration
Air quality impacts for criteria pollutants were all substantially below applicable standards.	Operational restrictions and monitoring/record-keeping requirements, beyond what is required to assure the facility remains below PSD thresholds, are not necessary to assure compliance with air quality standards.

2.0 BACKGROUND INFORMATION

2.1 Applicable Air Quality Impact Limits and Modeling Requirements

This section identifies applicable ambient air quality limits and analyses used to demonstrate compliance.

2.1.1 Area Classification

The Gateway Power Plant is proposed to be located in Ada County, Idaho. This area is designated as an attainment or unclassifiable for all criteria pollutants. The area operates under limited maintenance plans for PM_{10} and CO. There are no Class I areas within 10 kilometers of the facility.

2.1.2 Significant and Full Impact Analyses

If estimated maximum pollutant impacts to ambient air from the emissions sources associated with the proposed facility exceed the significant contribution levels (SCLs) of IDAPA 58.01.01.006.90, then a full impact analysis is necessary to demonstrate compliance with IDAPA 58.01.01.203.02. A full impact analysis for attainment area pollutants involves adding ambient impacts from facility-wide emissions to DEQ-approved background concentration values that are appropriate for the criteria pollutant/averaging-time at the facility location and the area of significant impact. The resulting maximum pollutant concentrations in ambient air are then compared to the National Ambient Air Quality Standards (NAAQS) listed in Table 2. Table 2 also lists SCLs and specifies the modeled value that must be used for comparison to the NAAQS.

Table 2. APPLICABLE REGULATORY LIMITS

Pollutant	Averaging Period	Significant Contribution Levels[a] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	Modeled Value Used[d]
PM_{10}[e]	Annual	1.0	50[f]	Maximum 1st highest[g]
	24-hour	5.0	150[h]	Maximum 6th highest[i]
Carbon monoxide (CO)	8-hour	500	10,000[j]	Maximum 2nd highest[g]
	1-hour	2,000	40,000[j]	Maximum 2nd highest[g]
Sulfur Dioxide (SO_2)	Annual	1.0	80[f]	Maximum 1st highest[g]
	24-hour	5	365[j]	Maximum 2nd highest[g]
	3-hour	25	1,300[j]	Maximum 2nd highest[g]
Nitrogen Dioxide (NO_2)	Annual	1.0	100[f]	Maximum 1st highest[g]
Lead (Pb)	Quarterly	NA	1.5[h]	Maximum 1st highest[g]

[a]IDAPA 58.01.01.006.90
[b]Micrograms per cubic meter
[c]IDAPA 58.01.01.577 for criteria pollutants
[d]The maximum 1st highest modeled value is always used for significant impact analyses
[e]Particulate matter with an aerodynamic diameter less than or equal to a nominal ten micrometers
[f]Never expected to be exceeded for any calendar year
[g]Concentration at any modeled receptor
[h]Never expected to be exceeded more than once in any calendar year
[i]Concentration at any modeled receptor when using five years of meteorological data
[j]Not to be exceeded more than once per year

2.1.3 Toxic Air Pollutant Analyses

Toxic Air Pollutant (TAP) requirements for PTCs are specified in IDAPA 58.01.01.210. If the emissions increase associated with a new source or modification exceeds screening emission levels (ELs) of IDAPA 58.01.01.585 or 586, then the ambient impact of the emissions increase must be estimated. If maximum ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of IDAPA 58.01.01.585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of IDAPA 58.01.01.586, then compliance with TAP requirements has been demonstrated.

2.2 Background Concentrations

Background concentrations were revised for all areas of Idaho by DEQ in March 2003[1]. Background concentrations in areas where no monitoring data are available were based on monitoring data from areas with similar population density, meteorology, and emissions sources.

Greystone's submitted analyses used suburban area default values for sulfur dioxide (SO_2), carbon monoxide (CO), and nitrogen dioxide (NO_2) because the greatest impact will be outside of the Boise urban area. DEQ verification analyses conservatively used the monitoring results from the Boise urban area as background concentrations for CO, NO_2, and annual PM_{10} (SO_2 monitoring has not been conducted in the Boise area).

1 Hardy, Rick and Schilling, Kevin. *Background Concentrations for Use in New Source Review Dispersion Modeling*. Memorandum to Mary Anderson, March 14, 2003.

Airshed modeling results were used for 24-hour PM_{10}. Table 3 lists applicable background concentrations.

Table 3. BACKGROUND CONCENTRATIONS		
Pollutant	**Averaging Period**	**Background Concentration[a] (μG/M³)[B]**
PM_{10}[c]	24-hour	84[d]
	Annual	27 (30.1)
Carbon monoxide (CO)	1-hour	10,200 (12,200)
	8-hour	3,400 (6,800)
Sulfur dioxide (SO_2)	3-hour	42
	24-hour	26
	Annual	8
Nitrogen dioxide (NO_2)	Annual	32 (40)
Lead (Pb)	Quarterly	0.08

[a]Values in parentheses are those used in the DEQ verification analyses, where those values differed from submitted values
[b]Micrograms per cubic meter
[c]Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
[d]Maximum modeled value associated with wintertime stagnation period

3.0 MODELING IMPACT ASSESSMENT

3.1 Modeling Methodology

Table 4 provides a summary of the modeling parameters used by Greystone in the submitted analyses.

Table 4. REFINED MODELING PARAMETERS		
Parameter	**Description/Values**	**Documentation/Addition Description**
Model	ISCST3	ISCST3, version 02035
Meteorological data	Boise surface data Boise upper air data	1986-1990
Terrain	Considered	Receptor, building, and emissions source elevations were determined using Digital Elevation Model (DEM) files
Building downwash	Considered	The building profile input program (BPIP) was used
Receptor Grid	Facility Boundary	25-meter spacing
	Grid 1	100-meter spacing out 2,000 meters from the stack
	Grid 2	250-meter spacing out to 5,000 meters
	Grid 3	500-meter spacing out to 10,000 meters

3.1.1 Modeling protocol and Methodology

The submitted air impact analyses were conducted by Greystone. A modeling protocol was submitted to DEQ prior to the application. Modeling was generally conducted using methods and data presented in the protocol and the *State of Idaho Air Quality Modeling Guideline*.

Boise Planning and Zoning Commission (Planning and Zoning) requested MVP to submit air quality impact analyses to evaluate the conditional use permit application. Planning and Zoning then requested DEQ to review the analyses submitted by MVP and provide comments back to Planning and Zoning. Appendix A to this memorandum provides DEQ's review of those analyses and presents several independent analyses conducted by DEQ to further assess potential air quality impacts. Some of these analyses were beyond the scope of Idaho minor source air permitting rules and standard procedures, but provide additional assurance that impacts will be within regulatory acceptable levels.

Greystone demonstrated compliance by assessing numerous operational scenarios. Emissions, stack gas temperature, and flow rates vary as a function of operational load, ambient temperature, and relative humidity. DEQ verification analyses conservatively used allowable emissions and worst-case release parameters. The lowest stack gas temperature and lowest flow velocity were selected from all the operational scenarios used by Greystone, even though many combinations of emissions and flow rates are not realistic.

3.1.2 Model Selection

ISCST3 was used by Greystone to conduct the ambient air analyses. ISCST3 is an EPA-recommended model for permitting applications. The model AERMOD was promulgated as the replacement for ISCST3 on November 9, 2005, and AERMOD is required for applications received by DEQ after November 9, 2006. ISCST3 is acceptable for this application because the application was received February 1, 2006, well before the date requiring AERMOD.

ISCST3 is not appropriate where ambient air receptors may be located within building recirculation cavities. In these instances ISCST3-PRIME, AERMOD, or SCREEN3 must be used. Exhaust from the combustion turbine are released with enough plume momentum and thermal buoyancy, and are released from a sufficiently elevated stack, to prevent entrainment in any building recirculation cavities; however, the plume from the fuel dew point heater could become entrained in the recirculation cavity of CT01 structure. Greystone elected to use SCREEN3 to assess impacts from the fuel dew point heater. SCREEN3 is a screening-level model that calculates maximum 1-hour plume centerline concentrations for a single source. Concentrations for averaging periods other than one hour are estimated by multiplying the 1-hour result by persistence factors listed in Table 5. Total project impacts are determined by conservatively adding maximum impacts from the turbine to those from the fuel dew point heater.

Table 5. SCREEN3 PERSISTENCE FACTORS

Conversion	Factor
1-hour to 3-hour	0.9
1-hour to 8-hour	0.7
1-hour to 24-hour	0.4
1-hour to annual	0.08

ISCST3-PRIME was used for DEQ verification analyses; therefore, separate analyses were not needed for the combustion turbine and the fuel dew point heater.

3.1.3 Meteorological Data

Surface and upper air meteorological data from 1986 through 1990 at the Boise airport were used by Greystone in the modeling analyses. These are the most representative data available. DEQ verification analyses were performed using Boise meteorological data for 1987 through 1991.

PCRAMMET, the meteorological data preprocessor for ISCST3, occasionally generates unrealistically low mixing heights as a result of interpolation algorithms used with the twice daily measured mixing heights. This problem was addressed in the DEQ verification analyses by changing all mixing heights below 50 meters to a value of 50 meters.

Impacts from the dew point heater were estimated by Greystone using SCREEN3 with the full meteorology option. This option calculates impacts using worst-case meteorological conditions for the source/receptor configuration used in the model.

3.1.4 Terrain Effects

The modeling analyses submitted by Greystone considered elevated terrain. Elevations of receptors, buildings, and emissions sources were calculated from United States Geological Survey (USGS) 7.5 minute Digital Elevation Model (DEM) files. Receptor elevations used in the model appeared to be correct, as verified by DEQ spot-checking.

3.1.5 Facility Layout

DEQ verified proper identification of the facility boundary and buildings on the site by comparing the modeling input to a facility plot plan submitted with the application.

3.1.6 Building Downwash

Downwash effects potentially caused by structures at the facility were accounted for in the dispersion modeling analyses. The Building Profile Input Program (BPIP) was used to calculate direction-specific building dimensions and Good Engineering Practice (GEP) stack height information from building dimensions/configurations and emissions release parameters for ISCST3 and ISCST3-PRIME.

Downwash effects were also considered in the SCREEN3 analyses performed by Greystone for the fuel dew point heater. Dimensions of the CT01 building were used in the analysis, since SCREEN3 can only consider one building.

3.1.7 Ambient Air Boundary

The property boundary was used as the ambient air boundary for the modeling analyses submitted by Greystone. DEQ assumed reasonable measures would be taken to assure the general public are excluded from access to the property.

3.1.8 Receptor Network

Considering the area where maximum impacts are predicted, DEQ determined the receptor grid was adequate to reasonably resolve the maximum modeled concentrations.

3.2 Emission Rates

Emissions rates used in the dispersion modeling analyses submitted by the applicant were reviewed against those in the permit application, the engineering Statement of Basis, and the proposed permit.

3.2.1 Criteria Pollutant Emissions Rates

Table 6 lists criteria emissions rates for sources included in the short-term and long-term dispersion modeling analyses. Greystone used numerous operational scenarios involving loads of 60 to 100 percent, over ambient temperatures between -20^{o} F to 110^{o} F. Emissions rates were calculated assuming a maximum of 10 startup/shutdown cycles for the 24-hour averaging period and continuous startup/shutdown cycles for the averaging periods less than 24 hours. Permitted long-term emissions rates for NOx, SO_2, and CO were based on limiting operations such that annual emissions remain below 249 tons per year. Annual allowable PM_{10} emissions were based on maximum hourly emissions combined with a maximum of 400 startup/shutdown cycles. Annual modeling results were conservatively based on the same emissions rates as used to assess 24-hour impacts. This will substantially overestimate impacts because of the higher number of startup/shutdown cycles. Using 10 cycles per day, as was used for 24-hour impacts, will result in 3,650 startup/shutdown cycles each year, rather than the stated maximum of 400. Annual modeling results were also based on the single operational scenario that yields the greatest impact. It is extremely unlikely that this scenario would persist during all operational periods.

DEQ verification analyses for short-term averaging periods were based on maximum allowable emissions rates rather than the more refined approach used by Greystone involving emissions specific to an operational scenario. Verification analyses for annual averaging periods were based on annual allowable emissions evenly distributed over 8760 hours.

3.2.2 TAP Emissions Rates

TAP emissions used in Greystone's modeling analyses were based on operational loads for specified scenarios, as was calculated for criteria pollutants. TAP emissions for specific operational scenarios are listed in the application and are not reiterated in this memorandum. DEQ verification analyses were performed using maximum TAP emissions as presented in the DEQ Statement of Basis. Table 7 lists maximum TAPs emissions as verified by DEQ. Dispersion modeling of TAP emissions are required for those TAPs having emissions exceeding the screening emissions levels (ELs) listed in IDAPA 58.01.01.585 and 586.

3.3 Emission Release Parameters

Exhaust from the turbine will vent through a 60-foot high rectangular stack having horizontal dimensions of 30 feet by 33 feet (effective diameter of 27 feet). Exhaust from the fuel dew point heater exhausts through an 18-foot high stack with a 2-foot diameter. The stated flow rate from the dew point heater is 3.8 meters per second at 1,000^{o} F. Emissions rates, flow rates, and stack gas temperatures vary according to the operational level. Release parameters for each modeled operational scenario are listed in Table 8.

Table 6. CRITERIA POLLUTANT EMISSIONS RATES USED FOR AIR IMPACT MODELING

Operational Scenario	Load	Amb. Temp[b] (F)	RH[c] (%)	Emissions Rates[a] (lb/hr)			
				PM_{10}[d]	SO_2[e]	CO[f]	NOx[g]
W060N1	60	-20	100	23.2	78.5	1,646	71.9
W060N2	60	0	100	22.6	75.6	1,646	69.4
W060N3	60	50	60	21.0	72.9[h] 70.7[i] 68.7[j]	1,646	63.3
W060N4	60	59	60	20.6	72.9[h] 70.0[i] 67.4[j]	1,646	62.1
W060N6	60	100	10	18.8	72.9[h] 66.3[i] 60.3[j]	1,646	55.8
W060N7	60	110	10	18.4	72.9[h] 65.5[i] 58.9[j]	1,646	54.4
W070N1	70	-20	100	25.4	87.9	1,646	64.9
W070N2	70	0	100	24.7	84.4	1,646	62.6
W070N3	70	50	60	22.9	76.4	1,646	57.1
W070N6	70	100	10	20.3	72.9[h] 69.4[i] 66.4[j]	1,646	50.1
W070N7	70	110	10	19.9	72.9[h] 68.6[i] 64.6[j]	1,646	48.8
W080N2	80	0	100	26.7	93.5	1,646	68.7
W080N3	80	50	60	24.8	84.4	1,646	62.6
W080N6	80	100	10	21.9	72.9[h] 72.7[i] 72.6[j]	1,646	54.5
W090N2	90	0	100	28.7	102.1	1,646	74.6
W090N3	90	50	60	26.7	92.2	1,646	67.9
W090N6	90	100	10	23.5	79.0	1,646	59.0
W100N1	100	-20	100	30.7	111.2	1,646	80.8
W100N2	100	0	100	31.0	111.5	1,646	81.0
W100N3	100	50	60	28.7	100.6	1,646	73.6
W100Y4	100	59	60	28.5	100.2	1,646	73.3
W100N5	100	90	20	26.0	89.2	1,646	65.9
W100Y5	100	90	20	27.6	96.6	1,646	70.9
W100N6	100	100	10	25.3	86.4	1,646	63.9
W100Y6	100	100	10	27.1	94.4	1,646	69.4
W100N7	100	110	10	24.7	83.7	1,646	62.1
DEQ[k]	NA	NA	NA	31.0[i] (29.8[l])	111.4[h,i] (56.6[l])	1,646	56.4[l]

[a]Long term rates assume 8760 hours/year of operation unless otherwise specified
[b]Ambient temperature (degrees Fahrenheit)
[c]Relative humidity (percent)
[d]Particulate matter with an aerodynamic diameter less than or equal to a nominal ten micrometers
[e.]Sulfur dioxide
[f.]Carbon monoxide
[g]Oxides of nitrogen
[h]Value used for 3-hour averaging period
[i]Value used for 24-hour averaging period
[j]Value used for annual averaging period
[k]DEQ verification analyses
[l]Annual emissions divided by 8760 hours/year

Table 7. TAP EMISSIONS RATES					
TAP	**Averaging Period**	**Emissions Rate (lb/hr)[a]**		**Screening Emissions Level (lb/hr)**	**Modeling Required**
		Combustion Turbine	**Fuel Heater**		
Acrolein	24-hour	0.013	ND[b]	0.017	No
Ethylbenzene	24-hour	0.065	ND	29	No
Naphthalene	24-hour	0.0026	Neg.[c]	3.33	No
Propylene oxide	24-hour	0.059	ND	3.2	No
Toluene	24-hour	0.26	Neg.	25	No
Xylene (total)	24-hour	0.13	Neg.	29	No
Acetaldehyde	annual	0.081	ND	3.0E-3	Yes
Benzene	annual	0.024	Neg.	8.0E-4	Yes
Cadmium	annual	ND	3.88E-6	3.7E-6	Yes
Formaldehyde	annual	1.4	Neg.	5.1E-4	Yes
POM (as Benzo(a)pyrene)	annual	0.0045	Neg.	2.0E-6	Yes

[a]Pounds per hour
[b]No data available
[c]Negligible emissions

Table 8. COMBUSTION TURBINE EMISSIONS RELEASE PARAMETERS			
Operational Scenario	*Load* (%)	*Stack Gas Temp (K)[a]*	*Stack Gas Flow Velocity (m/sec)[b]*
W060N1	60	828.8	18.0
W060N2	60	834.4	17.7
W060N3	60	851.6	16.8
W060N4	60	855.9	16.6
W060N6	60	875.9	15.5
W060N7	60	881.4	15.3
W070N1	70	828.8	19.7
W070N2	70	834.4	19.3
W070N3	70	851.6	18.3
W070N6	70	875.9	16.7
W070N7	70	881.4	16.4
W080N2	80	834.4	20.9
W080N3	80	851.6	19.8
W080N6	80	875.9	18.0
W090N2	90	834.4	22.5
W090N3	90	851.6	21.3
W090N6	90	875.9	19.3
W100N1	100	828.8	23.9
W100N2	100	834.4	24.3
W100N3	100	851.6	22.9
W100Y4	100	853.5	22.8
W100N5	100	871.5	21.3
W100Y5	100	860.8	22.3
W100N6	100	875.9	20.8
W100Y6	100	865.3	22.0
W100N7	100	881.4	20.4
DEQ[c]	NA	828.8	15.26

[a]Kelvin
[b]Meters per second
[c]Worst-case parameters used for DEQ verification analyses

3.4 Results for Significant and Full Impact Analyses

Results for the significant impact analyses are shown in Table 9. Full impact analyses were only required for SO_2 and NO_2 as per the submitted analyses. Conservative DEQ verification analyses indicated full impact analyses were also needed for 24-hour PM_{10} and CO. To assure regulatory approval, Greystone conducted full impact analyses for all criteria pollutants.

Table 9. SIGNIFICANT IMPACT ANALYSES				
Pollutant	**Averaging Period**	**Maximum Modeled Concentration (μg/m^3)[a]**	**Significant Impact Level (μg/m^3)**	**Full Impact Analysis Required**
PM_{10}[b]	24-hour	3.1 (12.3)	5.0	No (Yes)
	Annual	0.5 (0.87)	1.0	No (No)
Sulfur Dioxide (SO_2)	3-hour	89.2 (134.7)	25	Yes (Yes)
	24-hour	20.9 (48.7)	5	Yes (Yes)
	Annual	3.1 (4.5)	1.0	Yes (Yes)
Carbon Monoxide (CO)	1-hour	1224.9 (2870)	2,000	No (Yes)
	8-hour	200.9 (1219)	500	No (Yes)
Nitrogen Dioxide (NO_2)	Annual	6.2 (8.3)	1.0	Yes (Yes)

[a.]Micrograms per cubic meter. Values in parentheses are those obtained from DEQ verification modeling
[b]Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers

Table 10 provides a summary of the full impact analyses. All impacts are well below applicable standards.

Table 10. FULL IMPACT ANALYSES						
Pollutant	**Averaging Period**	**Modeled Design Concentration (μg/m^3)[a]**	**Background Concentration (μg/m^3)**	**Total Impact (μg/m^3)**	**NAAQS[b] (μg/m^3)**	**Percent of NAAQS**
PM_{10}[c]	24-hour	6.2[d] (9.2[e])	84	90.2 (93.2)	150	60 (62)
Sulfur Dioxide (SO_2)	3-hour	89.2[d] (126.6[f])	42	131 (169)	1,300	10 (13)
	24-hour	20.9[d] (46.7[f])	26	46.9 (72.7)	365	13 (20)
	Annual	3.1[g] (4.5[g])	8	11.1 (12.5)	80	14 (16)
Carbon Monoxide (CO)	1-hour	1224.9[d] (2806.1[f])	12,200	13,425 (15,006)	40,000	34 (38)
	8-hour	200.9[d] (1202.3[f])	6,800	7,001 (8,002)	10,000	70 (80)
Nitrogen Dioxide (NO_2)	Annual	6.2[g] (8.3[g])	40	46.2 (48.3)	100	46 (48)

[a]Micrograms per cubic meter. Values in parentheses are those obtained from DEQ verification analyses
[b]National Ambient Air Quality Standards
[c]Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
[d]Maximum 1st highest modeled concentration using a five-year data set
[e]Maximum 6th highest modeled concentration using a five-year data set
[f]Maximum 2nd highest modeled concentration using a five-year data set
[g]Maximum annual impact from modeling five separate years

3.5 Results for TAPs Analyses

Compliance with TAP increments were demonstrated by modeling TAP emissions increases (those TAPs with emissions exceeding the ELs) resulting from operation of the facility. Table 11 summarizes the ambient TAP analyses.

Table 11. RESULTS OF TAP ANALYSES				
TAP	**Averaging Period**	**Maximum Modeled Concentration (μg/m^3)[a]**	**AACC[b] (μg/m^3)**	**Percent of AAC or AACC**
Acetaldehyde	annual	1.84E-4 (6.19E-4)	4.5E-1	0.1
Benzene	annual	1.15E-4 (1.83E-4)	1.2E-1	0.2
Cadmium	annual	(6.37E-5)	5.6E-4	11
Formaldehyde	annual	4.11E-3 (1.07E-2)	7.7E-2	14
POM (as Benzo(a)pyrene)	annual	1.01E-5 (3.44E-5)	3.0E-4	11

[a]Micrograms per cubic meter. Values in parentheses are those obtained from DEQ verification modeling
[b]Acceptable Ambient Concentration or Acceptable Ambient Concentration for a Carcinogen

4.0 CONCLUSIONS

The ambient air impact analyses demonstrated to DEQ's satisfaction that emissions from the facility will not cause or significantly contribute to a violation of any air quality standard.

APPENDIX C

Detailed Requirements

P-060005

Emissions Limits

3.3 Nitrogen Oxides (NO_X) Emissions Limit – 40 CFR 60.4320

The permittee shall meet the emission limit for NO_X specified in Table 1 of 40 CFR 60 Subpart KKKK as 15 ppm at 15% O_2 or 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour (lb/MWh)) for new, modified, or reconstructed combustion turbine firing natural gas with heat input at peak load (HHV) greater than 850 MMBtu/hr.

3.4 Sulfur Dioxide (SO_2) Emissions Limit – 40 CFR 60.4330

The permittee shall comply with either Permit Condition 3.4.1 or Permit Condition 3.4.2.

3.4.1 The permittee shall not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

3.4.2 The permittee shall not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

3.5 Criteria Pollutant Emissions Limits – Being PSD Synthetic Minor

Emissions of nitrogen oxide (NO_X), sulfur dioxide (SO_2), and carbon monoxide (CO) from the CT01 stack shall not exceed any corresponding emissions limits listed in Table 3.2.

Table 3.1 COMBUSTION TURBINE EMISSIONS LIMITS[a]

Source Description	NO_X T/yr	SO_2 T/yr	CO T/yr
Combustion Turbine CT01	247.1	248.0	247.4

[a]The permittee shall not exceed the T/yr listed based on any consecutive 12-month period.

Operating Requirements

3.6 General Requirements – 40 CFR 60.4333

The permittee shall operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

3.7 Fuel Restrictions

CT01 shall be fired by natural gas exclusively.

3.8 Turbine Startup Restriction

The permittee shall under no circumstance commence startup of CT01 without prior, written DEQ approval of the protocol required by Permit Condition 3.13.

Monitoring and Recordkeeping Requirements

3.9 Nitrogen Oxides Monitoring Requirement – 40 CFR 60.4340

If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with Permit Condition 3.27 (40 CFR 60.4400) to demonstrate continuous compliance. As an alternative, you may install, calibrate, maintain and operate continuous emission monitoring system as described in Permit Condition 3.9.1 (40 CFR 60. 4335(b)) and 3.9.2. (40 CFR 60.4345) to demonstrate continuous compliance with Permit Condition 3.3.

3.9.1 In accordance with 40 CFR 60. 4335(b), (1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours;

3.9.2 In accordance with 40 CFR 60.4345, (a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to 40 CFR 60, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to 40 CFR 60 is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under 40 CFR 60 Subpart KKKK. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of 40 CFR are acceptable for use under 40 CFR 60 Subpart KKKK.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this permit condition. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of 40 CFR.

3.10 Exempted from Monitoring the Total Sulfur Content of the Fuel – 40 CFR 60.4365

The permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input, Permit Condition 3.4.2, for units located in continental areas using methodologies specified in Permit Condition 3.29 (40 CFR 60.4415). You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of 40 CFR is required.

3.11 Monitoring the Total Sulfur Content of the Fuel – 40 CFR 60.4360, 4370, and 4385

If you elect not to demonstrate sulfur content using options in Permit Condition 3.10 (40 CFR 60.4365):

3.11.1 In accordance with 40 CFR 60.4360, the permittee must monitor the total sulfur content of the fuel being fired in the turbine. The sulfur content of the fuel must be determined using total sulfur methods described in Permit Condition 3.29 (40 CFR 60.4415). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17), which measure the major sulfur compounds, may be used.

3.11.2 In accordance with 40 CFR 60.4370(b), the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

3.11.3 In accordance with 40 CFR 60.4370(c), *Custom schedules.* Notwithstanding the requirements of paragraph (b) of 40 CFR 4370, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this permit condition, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in 40 CFR 60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this permit condition are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in 40 CFR 60 Subpart KKKK. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this permit condition, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this permit condition. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this permit condition.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:
(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this permit condition. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this permit condition.

(B) Begin monitoring at six-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this permit condition. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this permit condition.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this permit condition. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this permit condition. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this permit condition shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of 40 CFR to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this permit condition.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this permit condition.

3.12 Carbon Monoxide Monitoring Requirements – Proposed by the Applicant

3.12.1 The permittee shall install, certify, operate, and maintain a CEMS consisting of a CO pollutant concentration monitor and an oxygen diluent gas monitor. The CEMS shall be equipped with an automated data acquisition and handling system for measuring and recording the CO concentration (in ppmv) and CO emissions rate (in lb/hr) discharged to the atmosphere from the CT01 stack. The permittee shall fully comply with all requirements set forth in 40 CFR 60, Appendices B and F.

3.12.2 Carbon Monoxide RATA

Within 60 days after achieving the maximum production rate at which CT01 will operate, but not later than 180 days after initial start-up of CT01, the permittee shall perform a RATA on the CO CEMS. The initial RATA, and any subsequent RATAs conducted to demonstrate compliance, shall be performed in accordance with 40 CFR 60, Appendix F.

3.13 Emissions Rates Monitoring for NO_x, CO, and SO_2 – Being PSD Synthetic Minor

3.13.1 Emissions Rate Quantification Protocol Requirement

Within 60 days of permit issuance, the permittee shall submit a protocol addressing the methodology to be used to quantify NO_x, CO, and SO_2 emissions rates from CT01 to DEQ for approval. The protocol shall explicitly describe and discuss the manner by which the permittee will utilize the data collected, and/or derived in accordance with Permit Conditions 3.9 through 3.12, to quantify emissions rates of NO_x, CO, and SO_2. The protocol shall include or identify, at a minimum, the source of all data to be used in the emissions rate quantification. The protocol must be sufficiently detailed to allow DEQ to reproduce and/or verify emissions rate estimates for purposes of determining compliance with Permit Condition 3.5.

3.13.2 NO_X, SO_2 and CO Emissions Rates Monitoring

The permittee shall monitor and record the information listed below. The information shall be compiled in accordance with the DEQ-approved protocol required by Permit Condition 3.13.1.

- The total NO_x emissions rate in tons per each calendar month after turbine startup.
- The total, cumulative NO_x emissions rate in tons per each consecutive 12-month period.
- The total CO emissions rate in tons per each calendar month after turbine startup.
- The total, cumulative CO emissions rate in tons per each consecutive 12-month period.
- The total SO_2 emissions rate in tons per each calendar month after turbine startup.
- The total, cumulative SO_2 emissions rate in tons per each consecutive 12-month period.

3.13.3 Within each 12-month rolling period, whenever the sum of the respective pollutant (i.e. NO_X, CO, and SO_2) approaches 235 T/yr but not to exceed 235 tons/yr, the permittee shall start recording the emissions daily in tons per day and calculate the total emissions daily for that period. The permittee shall stop operation of the turbine for the remaining time of that 12-month period when the sum reaches the annual emissions limit.

The permittee shall submit the report to DEQ whenever the sum of the respective pollutant (i.e. NO_X, CO, and SO_2) exceeds 235 T/yr for any 12-month rolling period.

3.14 General Provisions – 40 CFR 60 Subpart A

The permittee shall comply with the applicable New Source Performance Standards (NSPS) General Provisions specified in 40 CFR Part 60, Subpart A.

3.15 Recordkeeping

All records required under this Monitoring and Recordkeeping Requirements section shall be kept onsite for a minimum of five years and shall be made available to DEQ representatives upon request.

Reporting Requirements

3.16 Report Excess Emissions – 40 CFR 60.4375

For each affected unit required to continuously monitor emissions, or to periodically determine the fuel sulfur content under 40 CFR 60 Subpart KKKK, you must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

3.17 Identifying Nitrogen Oxides Excess Emissions Using CEMS Data – 40 CFR 60.4350

(a) All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b) (Permit Condition 3.9.2(b)), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of 40 CFR 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If the permittee has installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).
(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in unit of the emission standard under Permit Condition 3.3 (40 CFR 60.4320), using ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:
E = hourly NO_X emission rate, in lb/MWh,
$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,
$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, and
P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad (Eq. 2)$$

Where:
P = gross energy output of the stationary combustion turbine system in MW.
$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,
$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad (Eq. 3)$$

Where:
Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,
Q = measured steam flow rate in lb/h,
H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 10_6 = conversion from Btu/h to MW.
Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \qquad (Eq. 4)$$

Where:
E = NO_X emission rate in lb/MWh,
$(NO_X)_m$ = NO_X emission rate in lb/h,
BL = manufacturer's base load rating of turbine, in MW, and
AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this permit condition to assess excess emissions on a 4-hour rolling average basis, as described in Permit Condition 3.18(1) (40 CFR 60.4380(b)(1)).

3.18 Excess Emissions and Monitor Downtime Defined for NO_X – 40 CFR 60.4380

For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

For turbines using continuous emission monitoring, as described in Permit Conditions 3.9.1 and 3.9.2 (40 CFR 60.4335(b) and 40 CFR 60.4345)):

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in Permit Condition 3.3 (40 CFR 60.4320). For the purposes of 40 CFR 60 Subpart KKKK, a “4-hour rolling average NO_X emission rate” is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a “30-day rolling average NO_X emission rate” is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

3.19 Excess Emissions and Monitoring Downtime Defined for SO_2 – 40 CFR 60.4385

Excess emissions and monitoring downtime are defined as follows:

(1) In accordance with 40 CFR 60.4385(a), for samples of gaseous fuel, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(2) In accordance with 40 CFR 60.4385(c), A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

3.20 Performance Test Protocols

The permittee shall submit a test protocol, for each performance test required in the performance test section of this permit to DEQ for approval at least 30 days prior to the test date.

3.21 Performance Test Results

The permittee shall submit a written report of the performance test results, as required in the performance test of this permit to DEQ within 60 days of performing each respective test.

3.22 Test Protocols for CEMS Certification/Recertification Tests

The permittee shall submit a test protocol to DEQ for each certification and recertification of the NO_x and CO CEMS required by Permit Conditions 3.9.2 and 3.12 for approval. Each test protocol shall be submitted to DEQ for approval at least 30 days prior to the respective test date.

3.23 Initial Certification, Recertification, and Monitoring Plans for NO_X-CEMS

The permittee shall comply with the reporting requirements set forth in 40 CFR 75, Subpart G. In accordance with 40 CFR 75.60(b)(2), copies of all certification or recertification notifications, certification or recertification applications, and monitoring plans for NO_X–CEMS shall be submitted to DEQ. The copies shall be submitted to DEQ no later than the respective date specified in 40 CFR 75, Subpart G, for submission to the EPA Administrator.

In addition, the permittee shall submit a written report (including all raw field data, etc.) to DEQ for each certification or recertification test required in accordance with Permit Condition 3.9. Each report shall be submitted to DEQ within 60 days of the date on which the respective test was completed.

3.24 Results of Certification/Recertification Tests for CO-CEMS

The permittee shall submit a written report of the results of CO-CEMS certification/recertification tests to DEQ, within 60 days of performing each respective test.

3.25 Results of RATAs

The results of any RATAs conducted for compliance shall be submitted to DEQ within 60 days of the completion of the test.

3.26 Quality Assurance Procedures Requirements for CEMS

All CEMS data submitted to EPA and/or DEQ shall meet the quality assurance procedures in 40 CFR 60, Appendix F.

Performance Test

3.27 Conduct the Initial and Subsequent Performance Tests for NO_X – 40 CFR 60.4400

(a) The permittee must conduct an initial performance test within 60 days after achieving the maximum production rate at which the turbine will be operated, but not later than 180 days after initial startup of the turbine, as required in 40 CFR 60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:
E = NO_X emission rate, in lb/MWh
1.194×10^{-7} = conversion constant, in lb/dscf-ppm
$(NO_X)_c$ = average NO_X concentration for the run, in ppm
Q_{std} = stack gas volumetric flow rate, in dscf/hr
P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to 40 CFR 60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in Appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in 40 CFR 60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this permit condition, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of Appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) Per 40 CFR 60.4400(a)(3)(ii)(C), for turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least one meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) In accordance with 40 CFR 60.4400(b)(4), compliance with the applicable emission limit in Permit Condition 3.3 (40 CFR 60.4320) must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in Permit Condition 3.3 (40 CFR 60.4320).

(2) In accordance with 40 CFR 60.4400(b)(5), If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in Permit Condition 3.28 (40 CFR 60.4405)) as part of the initial performance test of the affected unit.

(3) In accordance with 40 CFR 60.4400(b)(6), The ambient temperature must be greater than 0 °F during the performance test.

3.28 Perform the Initial Performance Test If I Have Chosen to Install a NO_X-Diluent CEMS – 40 CFR 60.4405

If you elect to install and certify a NO_X-diluent CEMS under Permit Condition 3.9.2 (40 CFR 60.4345), then the initial performance test within 60 days after achieving the maximum production rate at which the turbine will be operated, but not later than 180 days after initial startup of the turbine, required under 40 CFR 60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under Permit Condition 3.3 (40 CFR 60.4320) and to provide the required reference method data for the RATA of the CEMS described under Permit Condition 3.9.1(40 CFR 60.4335).

(d) Compliance with the applicable emission limit in Permit Condition 3.3 (40 CFR 60.4320) is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

3.29 Conduct the Initial and Subsequent Performance Tests for Sulfur – 40 CFR 60.4415

(a) You must conduct an initial performance test within 60 days after achieving the maximum production rate at which the turbine will be operated, but not later than 180 days after initial startup of the turbine, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) for natural gas. The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using, for gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

(2) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of 40 CFR 60. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of 40 CFR 60, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:
E = SO_2 emission rate, in lb/MWh
1.664×10^{-7} = conversion constant, in lb/dscf-ppm
$(SO_2)_c$ = average SO_2 concentration for the run, in ppm
Q_{std} = stack gas volumetric flow rate, in dscf/hr
P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation; or

(3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of 40 CFR 60. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of 40 CFR 60 to calculate the SO_2 emission rate in lb/MMBtu. Then, use the following equation, Equation 1 in 40 CFR 60.4350(f), to calculate the SO_2 emission rate in lb/MWh.

For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:
E = hourly NO_X emission rate, in lb/MWh,
$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,
$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D–15a in appendix D to part 75 of this chapter, and
P = gross energy output of the combustion turbine in MW.